OFFSHORE PLATFORM

WITH VERTICALLY-RESTRAINED BUOY AND WELL DECK

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit, under 35 U.S.C. Section 119(e), of co-pending Provisional Application No. 60/478,914, filed June 16, 2003, and it is a continuation-in-part of co-pending Application Serial No 10/213,967, filed August 7, 2002, the disclosures of which are incorporated herein by reference.

FEDERALLY-SPONSORED RESEARCH OR DEVELOPMENT

Not Applicable

BACKGROUND OF THE INVENTION

[0002] The present invention relates to offshore platforms, and specifically to offshore platforms designed for dry tree applications. More particularly, the present invention relates to a new production and/or drilling riser system used in deep draft dry tree offshore platforms.

[0003] Conventional dry tree offshore platforms are low heave floating platforms, such as spars, TLPs (Tension Leg Platforms), and deep draft semi-submersible platforms. These platforms are able to support a plurality of vertical production and/or drilling risers. These platforms can comprise a well deck, where the surface trees (arranged on top of the riser) will be located, and a production deck where the petroleum product (e.g., crude oil or natural gas) will be distributed to a processing facility to separate water, oil and gas. These two decks are part of the hull of the offshore platform. In a conventional dry tree offshore platform, vertical risers running from the well head to the well deck are supported by a tensioning apparatus. These vertical risers are called Top Tensioned Risers (TTRs).

[0004] Offshore environmental conditions are often harsh. Actions of wind, waves and currents can have significant effects on an offshore structure, especially in the uppermost layer of the sea, between the surface and a depth of about 150 - 300 ft. (about 45m to about 90m), which is called the "near surface wave action zone". These actions attenuate with the water depth. In TLPs or semi-submersible platforms, the vertical risers are subjected to the effects of waves and currents

in the splash zone, which puts strain on the risers and can lead to VIV (Vortex Induced Vibrations), thereby requiring expensive VIV strakes to be installed on each riser. In spar platforms, the vertical risers are protected from the effects of waves and currents in the splash zone by a center well.

[0005] There are two conventional designs for applying tension to the TTRs respectively illustrated in Figures 10A and 10B. The first design, shown in Figure 10A, uses one or more passive buoyancy cans 10 to independently support a riser 12. Figure 10A shows a top tensioned riser arrangement 12 with buoyancy cans 10, of a type that is mainly employed on spar-type floating platforms, as disclosed and claimed in US 4,701,321 - Horton. Each riser 10 extends vertically from a wellhead 14 on the seabed to the top of a well deck 18 of the offshore platform. The riser passes from the wellhead 14 through a keel joint 20 into the center well 22 of the buoyancy cans 10. Inside the center well 22, the riser 12 passes through a stem pipe 24 that passes through the center of the buoyancy cans 10. The stem pipe 24 extends above the buoyancy cans 10 and supports the well deck 18 to which the riser 12 and a surface tree 26 are attached. The buoyancy cans 10 and the stem pipe 24 are guided at several locations in the center well 22 by a plurality of riser guides 28. Because the risers 12 are independently supported by the buoyancy cans 10 (relative to the hull), the hull is able to move up and down relative to the risers 12, and thus the risers 12 are isolated from the heave motions of the offshore platform. The buoyancy cans 10 need to provide enough buoyancy to support the required top tension in the risers 12, as well as the combined weight of the cans 10, the stem pipe 24, and the surface tree 26. With increased depth, the buoyancy required to support the riser system will correspondingly increase, requiring larger buoyancy cans 10. Consequently, the size of the center well 22 will increase proportionately. Designing and manufacturing individual buoyancy cans 10 for each riser 12 is also costly.

[0006] The second conventional design, shown in Figure 10B, uses an active hydraulic tensioning mechanism to independently support the risers 12. Each riser 12 extends vertically from the wellhead 14 to the production deck 32 of the offshore platform. The riser 12 is supported by active hydraulic cylinders 30 connected to the well deck 18 of the offshore platform, allowing the hull to move up and down relative to the risers 12 and thus partially

isolating the risers 12 from the heave motions of the hull. A surface tree 26 is connected to the top of the riser 12. As the required tension and stroke increase in magnitude, the size of the hydraulic cylinders 30 correspondingly increases and may become prohibitively expensive. Furthermore, the loads have to be supported by the offshore platform.

[0007] For TLPs and deep draft semi-submersible platforms, riser tensioning systems similar to the above-described designs can be used, although designs employing hydraulic tensioners are more common.

[0008] In both designs, the tensioning device allows the isolation of the risers from the heave motions of the offshore platform. However, as each riser is independently supported, the well deck as well as the production deck will move up and down relative to the surface trees. Consequently, in order to absorb these motions, high pressure flexible jumpers 34 (Figures 10A and 10B) are required to connect each surface tree in the well deck area to a manifold (not shown) on the production deck 32 which carries the liquid petroleum product to a processing facility to separate water, oil and gas. The high pressure flexible jumpers 32 are expensive compared to rigid piping and can lead to design problems, especially in high pressure / high temperature environments.

[0009] The prior art, as exemplified in US 5,439,321, US 4,995,762 and US 4,913,238, proposes to connect all the TTRs to a single (independent from the work platform) buoyancy apparatus in order to create a small well deck TLP to receive the riser. The small well deck TLP is anchored with tendons connected to the outer periphery of the buoyancy apparatus. The small well deck TLP has a low natural period in the range of 2-3 seconds, and will have the same problems as the conventional TLP (e.g., high cost, springing and ringing problems). Furthermore, as the small well deck TLP is completely independent from the work platform, the tendons will have to be designed to limit the horizontal motion of the small well deck TLP. These concepts will require at least four tendons arranged on the outer periphery of the small well deck TLP, and risers will be arranged in between these tendons. In addition to the cost of these tendons, one must solve the problem of collision between the risers themselves, and between the risers and tendons, by providing sufficient spacing between the several risers, and between the risers and the tendons.

This leads either to a large buoy to accommodate several risers, or a small number of risers supporting by the small well deck TLP. Furthermore, high pressure jumpers are still required to connect each surface tree to the manifold of the production deck.

SUMMARY OF THE INVENTION

[0010] The present invention addresses the problems just described and proposes a new passive tensioning system for top-tensioned risers in dry tree floating platforms, most advantageously spars and deep draft semi-submersible platforms. Rather than tensioning independently each vertical riser with individual buoyancy cans or individual hydraulic tensioners, the present invention provides for tensioning all the risers with a single buoyancy apparatus, which can be a large single buoyancy can or a multi cellular buoyancy apparatus. For the purposes of this description, a "deep draft" semi-submersible floating platform is defined as a low-heave platform having a draft of at least about 150 ft. (45m), and able to guide or receive top-tensioned risers.

[0011] A first unique feature of the present invention is that, contrary to prior art (where the well deck is supported by the offshore platform), the single buoyancy apparatus includes the well deck arranged on its top surface. Since the risers are connected to the same buoyancy apparatus, they act as a single riser system, and surface trees on top of the risers can be rigidly attached on top of the buoyancy apparatus. Consequently, all the surface trees can be connected to a manifold on the well deck (not the production deck) with rigid piping. The crude oil will be choked down in the entry of the manifold, and, contrary to the prior art, one or just a few low pressure flexible jumper(s) (or rigid articulated arms) can be used to carry the liquid petroleum product (e.g., crude oil) to the processing equipment on the production deck. The use of a small number (as low as one) of low pressure flexible jumpers or articulated rigid arms will considerably reduce the cost of the riser system as well as the required deck room.

[0012] A second unique feature is the use of concentric tendons attached at the well deck (or top of the single buoyancy apparatus) on the center line of the single buoyancy apparatus. When one tendon is used, it will be connected to the well deck on the centerline of the buoyancy apparatus. When more tendons are used, their centroid will be close to the vertical centerline of the apparatus. The use of central tendons limits the over-stressing of the risers and the requirement

for a reinforced wellhead foundation, as tension loads will be withstood principally by the tendons themselves and their foundation.

[0013] The use of concentric tendons will provide much flexibility in the design of the tendons to achieve the required dynamic behavior. Three factors are important in the design of the tendons: (1) The tendons must be strong enough to withstand the maximum static and dynamic loads imparted to them by the spar. (2) The buoyancy apparatus must impart sufficient upward tension at the top of the tendons to prevent them from going slack at the base. (3) The tendons must have sufficient axial stiffness to keep the riser system from going into resonance due to cyclic wave forces.

[0014] Contrary to the prior art, the present invention avoids the need to have several tendons arranged in the outer periphery of the buoy, and thus reduces the cost of the riser system and simplifies the resolution of the problems of riser and riser/tendon collisions.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] Figure 1 shows a cross-sectional view of one exemplary embodiment of a floating platform in which the risers are supported by a single buoyancy system and are coupled to a central tendon assembly for restraining the vertical motion of a single buoyancy system;

[0016] Figure 2 shows a cross sectional view of the floating platform in which the risers are supported by a single buoyancy system, vertically restrained by central tendons, the riser being independent from the central tendon;

[0017] Figure 3 shows a cross sectional view of the floating platform in which the risers are supported by a single buoyancy system;

[0018] Figure 4 shows a cross-sectional view of the floating platform in which the single buoyancy system also supports the drilling rig and its associated equipment;

[0019] Figure 5 shows a top view of the well deck arrangement;

[0020] Figure 6A is an elevational view, partially in axial cross-section, showing one exemplary embodiment of the tendon riser arrangement;

[0021] Figure 6B is a cross-sectional view taken along line 6B – 6B of Figure 6A;

[0022] Figure 7 shows another exemplary embodiment for the single buoyancy system wherein the buoyancy system comprises a plurality of vertical tubes closely spaced and connected together through elongated vertical webs;

[0023] Figure 8 shows the use of the invention in a deep draft semi-submersible platform;

[0024] Figure 9 shows one exemplary embodiment of the well deck arrangement on top of the buoyancy system; and

[0025] Figures l0A and l0B show prior art riser systems.

DETAILED DESCRIPTION OF THE INVENTION

[0026] Figure 1 shows one exemplary embodiment of the invention used in a spar type floating platform 100. Figure 1 shows the spar type platform 100 having a spar hull 102 defining a center well 104. A vertically restrained buoyancy apparatus 106 is guided in at least two locations (upper and lower) within the center well 104 of the spar hull 102. This specific spar type platform 100 comprises an upper hull and a lower hull. The upper hull and the lower hull share the continuous hollow center well 104, which surrounds and guides the center well buoyancy apparatus 106. The upper hull includes a cellular structure comprising several compartments 108 for buoyancy purpose (void tanks and variable ballast tanks). The lower hull includes a sleeve 110 with a fixed ballast 112 near the bottom of the lower hull to lower the center of gravity and thus improve the stability of the platform 100. The spar type platform 100 supports a work platform 114 comprising a production deck 116, compartments 118 for crew quarters and utilities, and a drilling deck 120 for drilling equipment, such as a drilling rig 122. The floating platform 100 is moored with lateral mooring lines 124 in a taut leg mooring configuration or

catenary mooring configuration. The lateral mooring lines 124 are designed to limit the horizontal movement of the floating platform 100 relative to seabed wellheads to specified limits to prevent the risers (described below) from being over stressed.

[0027] Turning now to the riser system, plural top-tensioned risers 126 are tensioned by a single buoyancy apparatus 106 guided in the center well 104 of the spar hull 102. The buoyancy apparatus 106 can be a single large buoyancy can or a multi-cellular buoyancy system (described below and shown in Figure 7). Although the spar hull 102 constrains the center well buoyancy apparatus 106, the center well buoyancy apparatus 106 is itself free floating within the center well 104. Because the spar hull 102 and the center well 104 are each free-floating, the spar hull 102 moves to accommodate the environmental forces acting on it, and thus moves with respect to the vertically restrained center well buoyancy apparatus 106. Thus the spar hull 102 heave motion is decoupled from the center well buoyancy apparatus 106. This isolates the risers 126 that are supported by the center well buoyancy apparatus 106 from the heave motion of the spar type platform 100 due to waves and currents. Furthermore, at least first and second pluralities of guides 128 are provided in the center well 104 at selected, axially-spaced locations, and at least at upper and lower locations, to guide the buoyancy apparatus 106 within the center well 104. By reducing the peripheral gap between the spar hull 102 and the buoyancy apparatus 106, the guides 128 significantly reduce the impact loads between the hull 102 and the buoyancy apparatus 106 due to wave and current actions on the outer hull. Preferably, the buoyancy apparatus 106 and the guides 128 are in actual physical contact. To absorb, and thereby further reduce, the impact loads, the guides 128 advantageously include compliant pads (such as elastomeric pads) (not shown) that are positioned to be compressed against the buoyancy apparatus 106.

[0028] A unique feature of this invention is that a well deck 130 is positioned on top of the buoyancy apparatus 106, and all the risers 126 extend from the well deck 130 to wellheads 132 on the seabed.

[0029] In this specific embodiment, at least one central tendon assembly 134, comprising at least two concentric tubular tendon elements 136 (Figures 6A, 6B), secures the buoyancy apparatus

106 to the seabed. As shown in Figure 1, the tendon assembly 134 is attached at its upper end to the center of the well deck 130, and it extends down along the centerline of the buoyancy apparatus 126 to a tendon foundation in the seabed. The tendon foundation is of conventional design, described more fully below, comprising a caisson pile 138 anchored in the seabed, and a connective sleeve 140 connecting the tendon assembly 134 to the caisson pile 138. The advantage of using a central tendon assembly 134 is that it can be designed (in terms of the physical characteristics of the tendons the tendon foundation) to withstand most of the tension load, thereby reducing the tension loads in the risers 126. Thus, the requirement for reinforced foundations for the wellhead 132 will be further reduced, which is particularly advantageous in ultra deep water where the tension requirement can be quite critical.

[0030] As shown in Figures 6A and 6B, the tendon assembly 134 may be designed specifically as a tendon, or it may be designed as a riser that functions as a tendon with a reinforced wellhead foundation. In this embodiment, the tendon assembly 134 and a plurality of surrounding risers 126 are coupled together with a plurality of vertically-spaced riser spacers or guides 144, only one of which is shown in the drawings. The coupling of the risers 126 with the tendon assembly 134 helps prevent the risers 126 and the tendon assembly 134 from clashing or colliding with one another due to floating platform movement. It will not be necessary to space the several tendon assemblies from each other to avoid colliding, and a smaller center well 104 can be used which will significantly reduce the cost of the riser assembly 134 as well as the cost of the floating platform 100. Furthermore, the tension factor required for the risers 126 will be smaller, because the risk of colliding is reduced, thus reducing the size of the buoyancy apparatus 126. The coupling of the risers 126 with the tendon assembly 134, as well as the design of the tendon assembly 134 and the riser 126, will be explained in further detail below.

[0031] As shown in Figure 1, the upper portions of the risers 126 are uncoupled from the tendon assembly 134 within the upper portion of the center well 104, to allow the connection of each riser 126 to a respective surface tree 170, and the connection of tendon assembly 134 to a tendon socket or slot 146 (Figure 5) in the well deck 130. Similarly, the bottom portions of the risers 126 are uncoupled from the tendon assembly 134 to allow the connection of the risers 126 to their respective wellheads 132 and the connection of the tendon assembly to the tendon

foundation.

[0032] Figure 2 shows another exemplary embodiment of the invention used in a spar type floating platform 200, which includes risers 226 that are uncoupled from a tendon assembly 234. This embodiment provides a simplified riser and tendon construction (no need of riser spacers or guides), but the risers 226 and the tendon assembly 234 will have to be sufficiently spaced and will have to be tensioned sufficiently to avoid any collision between the risers 226 themselves and between the risers 226 and the tendon assembly 234. Accordingly, this embodiment requires a center well 204 that must be larger than that of the embodiment of Figure 1.

[0033] Figure 3 shows another exemplary embodiment of the invention used in a spar type floating platform 300. In this particular embodiment, there is no specific tendon used for vertically restraining the single buoyancy apparatus 306. Instead, this embodiment employs risers 326 and wellhead foundations 346 that are designed to vertically restrain the center well buoyancy apparatus 306.

[0034] Figure 4 shows another exemplary embodiment of the invention used in a spar type floating platform 400. This particular embodiment employs a center well buoyancy apparatus 406 that, in addition to a well deck 430, supports a drilling deck 420 with a drilling rig 422 and its associated equipment (drilling and work over), while the work platform supported by the floating structure comprises a production deck 416 with compartments 418 for crew quarters and utilities. The decks 416, 420 are conventional decks used on floating structures such as spars, TLPs or deep draft semi-submersible platforms. As the buoyancy apparatus 406 is vertically restrained, the drilling and work over operations will be less weather dependant.

[0035] In some embodiments, because there will be no relative vertical motion between the drilling riser and the drilling rig, there will be no requirement for a slip joint arranged on the drilling riser to absorb these vertical motions. The embodiment of Figure 4 employs risers 426 and tendons 442 that are coupled; however, the risers and the tendons can be uncoupled as shown in Figure 2, or the buoyancy apparatus can be vertically restrained by the riser itself, as shown in Figure 3. The embodiment of Figure 4 does, however, require additional buoyancy to

support the extra weight of the drilling/work over equipment.

[0036] As illustrated in Figures 1-4, the tendons and/or the risers are secured to the seabed at one end (wellhead or tendon foundation), and to the well deck on the center well buoyancy apparatus at the other end.

[0037] Figure 5 shows a horizontal cross sectional view of an example of a well deck assembly 500. The well deck assembly includes a well deck 130 having a tendon socket or slot 146 in its center to receive a tendon assembly 134. Around the tendon slot 146 are several riser sockets or slots 548. There is a space that serves as a tendon riser center well 550 around the tendon socket 146 to provide space for running equipment down to the seabed (for example landing bases, blow-out preventers, or any other equipment that will occur to those of ordinary skill in the art). On either side of the tendon riser center well 550 is a drilling well or moon pool 552. The moon pools 552 also provide space for performing drilling and work over operations or for running equipment down to the seabed. As shown in Figure 5, the center well buoyancy apparatus 106 is guided with a plurality of guides 128 (four guides, in this example), arranged around its perimeter. The number of guides 128 may be varied from as few as two to five or more, depending on the loads they are to absorb.

[0038] In Figures 1 to 5, only one tendon assembly 134 attached to the well deck 130 and extending down the centerline of the buoyancy apparatus 106 is shown. However, in other embodiments, there may be more than one tendon assembly aligned and/or parallel with the vertical centerline of the buoyancy apparatus. The various other embodiments may employ multiple tendon assemblies (not illustrated), closely arranged around the central tendon assembly.

[0039] As further shown in Figures 1-4, the tendon assembly 134 is secured to the seabed by a caisson pile 138, which is alternatively called an anchor caisson or a suction pile. The caisson pile 138 secures the tendon assembly 134 to the seabed. As shown in Figure 1, the tendon assembly 134 may optionally be connected to the caisson pile by the tendon connection sleeve 140, which is located in the center of the caisson pile 138, through which the bottom end of the

tendon assembly 134 is fixed to the seabed. Radial plates 154 connect the tendon assembly 134 to the interior wall of the connection sleeve 140.

[0040] To install the caisson pile 138, in one embodiment, the caisson pile 138 is pushed into the seabed by pumping water out of its interior. As water is pumped out, the ambient external water pressure pushes the caisson pile 138 down into the seabed. In other embodiments, the caisson pile 138 is pushed into the seabed by means of submersible pumps (not shown), airlifts (not shown), or any other method that may suggest itself to those of ordinary skill in the art. With the caisson pile 138 firmly anchored in the seabed, the tendon connection sleeve 140 connects the tendon assembly 134 to the caisson pile 138, thereby securing the tendon assembly 134 to the seabed.

[0041] In still another embodiment, at least one of the tubular tendon elements 136 of the tendon assembly 134 is drilled into the seabed and anchored therein by cement. This increases the pull-out resistance of the tendon assembly 134. The tendon connection sleeve 140 is extended out of the bottom of the caisson pile 138, thereby providing a connector through which the tendon elements 136 are drilled and connected.

[0042] It will be appreciated that the tendon assembly 134 may be secured to the seabed by any other method that may suggest itself to those of ordinary skill in the art.

[0043] Figures 6A and 6B show the structural details of one exemplary embodiment of a tendon assembly 134. The tendon assembly 134 comprises multiple (at least two) concentric tubular tendon elements 136. The concentric tubular elements 136 are secured to the well deck 130 on the vertical centerline of the center well buoyancy apparatus 106, and they extend down to an anchor assembly at the seabed, as discussed above. The use of concentric tubular tendon elements 136 provides great flexibility in the design of the tendons to achieve the required dynamic behavior.

[0044] Three factors are important in the design of the tendon assemblies 134: (1) The tendon

assemblies 134 must be strong enough to withstand the maximum static and dynamic loads imparted on them by the buoyancy apparatus 106. (2) The buoyancy apparatus 106 must impart sufficient upward tension at the top of the tendon assemblies 134 to prevent them from going slack at the bottom. (3) The tendon assemblies 134 must have sufficient axial stiffness to keep the riser/tendon assembly system from going into resonance due to cyclic wave forces. By varying the number of concentric tubular tendon elements 136, both the strength and spring characteristics are varied to meet specific design requirements on a case-by-case basis, as will occur to those of ordinary skill in the art.

[0045] There are other benefits stemming from the above-described concentric tendon design. For example, corrosion and fatigue are minimized by the use of corrosion inhibitors in the annular spaces defined between the concentric tubular elements 136. Furthermore, the use of multiple tubular tendon elements 136 provides redundancy compared to prior art tendons, should one of the tubular elements 136 fail. Another benefit is that the annular spaces can be pressurized to detect cracks and to check joint integrity.

[0046] As best shown in Figure 6A, the tubular tendon elements 136 may further comprise conventional oilfield casing joints with a flanged coupling 156. In various embodiments, the casing joints are of various sizes, depending on the required tensile loads. These loads vary on a case-by-case basis, as will occur to those of ordinary skill in the art.

[0047] In one embodiment, the tendon assembly 134 is installed in sections, in a section-by-section sequence, using the drilling rig 122 on the platform. Each section is installed on the deck and lowered using the rig, and the sections are connected using the flanged couplings 156. The advantages of installing the tendon assembly 134 in sections in this manner using the platform's own drilling rig will be readily apparent to those skilled in the art.

[0048] Figure 6B shows a cross section of the tendon assembly 134 of Figure 6A, showing one of the riser guides or spacers 144, which is also shown in Figure 6A. Each of the riser guides 144 couples each tendon assembly 134 to the adjacent risers 126. The riser guides 144 separate the risers 126 from one another and from the central tendon assembly 134, thereby preventing

the risers 126 and the tendon assembly 134 from clashing or colliding with each other. Each of the riser guides 144 comprises a central tendon conduit 158, through which the tendon assembly 134 passes, and a plurality of riser conduits 160 through which the risers 126 pass. The riser guides 144 are secured to the tendon assembly 134, and they may or may not be secured to the risers 126. As mentioned above, in the preferred embodiments of the invention, there are several vertically-spaced riser guides or spacers 144, separated by a vertical distance of about 15 ft. (4.5m) to about 70 ft. (21m), depending on the design parameters of the particular platform.

[0049] The tendon conduit 158 and the riser conduits 160 are rigidly connected and separated by a web of separation members 162. By rigidly separating the riser conduits 160 and the central tendon conduit 158, the risers 126 passing through the riser conduits 160 are separated from the central tendon 134 assembly passing through the tendon conduit 158. This prevents the risers 126 and the tendon assembly 134 from clashing or colliding below the keel of the platform due to waves, currents, and floating platform motion, which can occur even when it is subjected to light ocean currents. In other embodiments (e.g., that of Figure 2), the risers are not coupled to the tendon assembly by means such as the riser guides 144.

[0050] In the various embodiments of the present invention, a wide range of riser types may be used to connect the wellhead to the platform. The various types of risers include those used for drilling, production, and workover, as will occur to those skilled in the pertinent arts. For example, in alternative embodiments, the risers are drilling risers used with full sub-sea blow-out preventor (BOP) stacks, pressure risers with surface BOPs, and those used with split BOPs (e.g., a surface BOP for well control and a limited function BOP on the seabed). Still further embodiments may employ production risers and workover risers used with surface trees, sub-sea trees, split trees, wet trees, dry trees, or any other type of tree that may suggest itself to those skilled in the pertinent arts. In still another embodiment, the platform is designed for vertical entry into the well. Alternatively, the platform may be designed for any other directional entry into the well.

[0051] The spring characteristics of the risers and/or tendons, when acting together, have to be such that the riser system does not respond significantly to the waves, taking into account the

mass of the system and the draft of the floating platform. A plurality of risers and/or tendons will act together with a spring characteristic and a strength characteristic for the group of risers and/or tendons. Said differently, the risers and /or tendons act as a system, and their structural and spring properties achieve a uniform behavior for the group of riser and/or tendons.

[0052] One of the key aspects of this invention is the interaction between the risers or of the risers with the tendons when subjected to the movement of the floating support. As an example, when the floating platform is subjected to environmental forces, the distance between the wellhead on the seabed and the riser slot at the keel increases for the upstream riser and decreases for the downstream riser. Should a tendon be used, these distances will be also different. This means that the spring characteristics, in consideration of the hydrodynamic and gravitational forces, have to be selected so that the riser system will act in unison, and the separation between the risers will be maintained to avoid clashing and collisions as the floating platform moves.

[0053] Reference is again made to Figures 1-4. As the riser system is protected by the center well of the spar platform, the riser system will be excited only at the keel of the spar (for example, at about 500 ft or about 150m of water depth). Because the influence of waves and currents is minimized at this water depth and the area of excitation is small, the natural period of the riser assembly when the tendons and/or risers are connected does not need to be as short as the period of a conventional TLP and thus can be designed to be above the 2 to 3 second range. Thus, the requirement for axial stiffness will be reduced, and the tendon will require considerably less steel than a comparable tendon for conventional TLP.

[0054] Figures 1-4 illustrate the use of the present invention in a spar type floating platform. However, the invention may be applied to any deep draft floating platform, such as for example, conventional deep draft submersible platforms or self-installing deep draft submersible platforms.

[0055] Figure 8 shows the use of the present invention in a deep draft semi-submersible platform 600. As shown, a vertically restrained buoy 606, which supports a plurality of top-tensioned

risers (TTRs) 608, is guided within the hull of the deep draft semi-submersible platform 600 by a lower guide assembly 610 provided in the base 612 of the floating platform 600, and an upper guide assembly 614 provided in a work deck 616 supported by the hull. In this specific example, the single buoy 606 supports only a well deck 618 and the TTRs 608. However the buoy 606 can be designed to support the drilling deck and the drilling equipment as shown in Figure 4 for a spar-type platform. In this example, the buoy 606 is vertically restrained by the TTRs 608 only (as shown in Figure 3 for a spar-type platform). Alternatively, however a tendon assembly coupled or uncoupled with the riser can be used to vertically restrain the buoy 606. As opposed to a spar type platform, this vertically restrained buoy 606 will not be protected by a center well in the splash zone, and will be subjected to wave and current action which can lead to VIV problems. Since the diameter of the vertically restrained buoy 606 is large compared to a riser 608, the tension of the riser system can be designed to limit the VIV problem, or VIV strakes (not shown) can be provided on the outer periphery of the buoy 606.

[0056] Turning now to another feature of this invention, the vertically restrained buoy is guided by guide assemblies provided in the floating platform in at least two locations (upper and lower), whether the platform is a spar-type platform or a deep draft semi-submersible platform. While the floating platform is pitching, the contact loads between the buoy and the guide assemblies provide to the floating platform a restoring moment. This restoring moment allows an improvement (reducing the pitch angle) in the pitch motion of the floating structure. Indeed, this resulting moment is proportional to the weight of the risers supported by the buoy (which can be quite important, especially in deeper water).

[0057] Figure 7 shows another embodiment of the vertically restrained buoy. In all the embodiments already described, the vertically restrained buoy comprises a single, large buoyancy can. To achieve a high degree of compartmentalization, the buoy must be divided into compartments by a plurality of internal lateral bulkheads, thereby increasing the cost of manufacturing the buoy. Furthermore, because the risers and/or tendons pass through the buoy, the intersections between the risers and the bulkheads must be sealed by welding using a heavy welding procedure. In the embodiment shown in Figure 7, a vertically restrained buoyancy apparatus 700 comprises an assembly of a plurality of vertical tubes 702 closely spaced and

connected together by vertically-elongated webs 704. This arrangement provides a high degree of compartmentalization with few bulkheads and thus at a reduced cost. Furthermore, the risers 126 can be arranged around the vertical tubes 702 (i.e. in the interstices defined in between the vertical tubes) and will not have to cross through any buoyancy compartment, thereby avoiding the problem of sealing the intersections of the risers with the bulkheads.

[0058] In all the described embodiments, the well deck is supported directly by the vertically restrained buoy, the surface trees are attached on the well deck, and there are no relative motions between the surface trees and the well deck. To carry the crude oil to the production deck and the process equipment to separate oil, water and gas, high pressure flexible jumpers can be used to connect each sub-sea tree to the production deck manifold. However, a unique feature of the present invention, shown in Figure 9, is that contrary to the prior art (where the well deck is supported by the offshore platform), the single buoyancy apparatus 106 includes the well deck 130 arranged on its top surface. Since the risers 126 are connected to the same buoyancy apparatus 106, they act as a single riser system, and surface trees 170 connected to upper ends of the risers 126 can be rigidly attached to the top of the buoyancy apparatus 106.

[0059] Consequently, all the surface trees 170 can be connected to a manifold 172 situated on the well deck 130 (rather than the production deck) with rigid piping 174. The crude oil will be choked down by a pressure-reduction choke 176 in the inlet of the manifold 172, and, contrary to the prior art, as few as one low pressure flexible jumper 178 (or, alternatively an articulated rigid arm, not shown) can be used to carry the crude oil to the processing equipment on the production deck 116. The use of just one flexible jumper 178, or perhaps a few flexible jumpers (or articulated rigid arms) will considerably reduce the cost of the riser system as well as the required deck room.